Service Date: May 10, 1989

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER of the Application of MONTANA POWER COMPANY To Re-structure Natural Gas Rates	UTILITY DIVISION DOCKET NO. 87.8.38
IN THE MATTER of The Application of MONTANA POWER COMPANY For Authority to Implement a Natural Gas Incentive Rate.	DOCKET NO. 87.3.16
IN THE MATTER Of The Application of MONTANA POWER COMPANY For Authority To Implement An Experi-mental Industrial Market Retention Rate For Natural Gas.	DOCKET NO. 85.7.32
IN THE MATTER Of The Application of MONTANA POWER COMPANY'S Recovery of the Interruptible Market Reten-tion Rate Revenue Differential as of August 31, 1987.	DOCKET NO. 87.10.57
IN THE MATTER of the Application of MONTANA POWER COMPANY'S Unre-flected Gas Cost Account Balance as of August 31, 1987, and Its Gas Tracking Proposal for the Period September 1, 1987 to August 31, 1988.	DOCKET NO. 87.10.58
IN THE MATTER of the Application of MONTANA POWER COMPANY'S Unre-flected Gas Cost Account Balance as of August 31, 1986, and its Gas Tracking Proposal for the Period	DOCKET NO. 86.12.68

September 1, 1986 to August 31,)
1987.) ORDER NO. 5410

FINAL ORDER ON COST OF SERVICE

APPEARANCES

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BEFORE:

CLYDE JARVIS, Chairman
HOWARD L. ELLIS, Vice Chairman
JOHN B. DRISCOLL, Commissioner
TOM MONAHAN, Commissioner
DANNY OBERG, Commissioner

FINDINGS OF FACT

ORGANIZATION

This order summarizes the costing and pricing testimony received in this docket, and includes a Public Service Commission (Commission) decision on costing and pricing. In Part I, a brief history is provided of both Commission policy on Montana Power Company (MPC or Company) gas costing and pricing, and the course of these proceedings. This is followed by a review of MPC's testimony on cost of service and rate design, and the testimony of Montana Consumer Counsel (MCC), Great Falls Gas (GFG), Shelby Gas and Stone Container. MPC rebuttal testimony is included, as appropriate, in the review of intervenor testimony. The testimony of MPC and other parties on transmission issues is excluded, except that relating to transmission cost of service.

PART I

Background

In addition to procedural background, this section provides a flavor of the Commission's cost of service and rate design policies from two earlier dockets. This section also reviews interim decisions in two dockets regarding market retention and incentive pricing.

For the MPC gas utility, class cost of service and rate design issues have been addressed in two dockets during the past 10 years. First, in Phase II of Docket No. 6618, Order No. 4521b was issued in November, 1979. In that order, the Commission found persuasive the fundamental economic arguments in support of volumetric costing and pricing made by Dr. Wilson and Dr. Power (appearing on behalf of the Montana Consumer Counsel and District XI Human Resource Council, respectively) as bolstered by the testimony of Dr. Phillips (appearing on behalf of MPC). The Commission rejected the Company's proposed Seaboard approach in favor of, primarily, Dr. Wilson's volumetric approach to cost allocation in which total costs are divided by normalized sales. Dr. Wilson emphasized that the marginal cost of gas supply and, in turn, prices, should reflect economic costs.

With regard to rate design, the Commission found that the objectives of conservation, efficiency, and equity were promoted in the long run by marginal cost-based gas prices. Over opposition by several parties, the Commission adopted Dr. Power's inverse elasticity-based inverted price structure. Dr. Wilson supported seasonal price differences. As a result, a seasonally discounted gas price was tariffed for the Firm class. The revenue short-fall associated with the seasonal discount for the Firm class was not spread to the Utility or Interruptible classes.

In Docket No. 80.4.2 the most recent MPC gas cost of service and rate design order was issued (No. 4714a, December, 1980). While no party performed a marginal cost study, the merits of such a study were weighed against those of the tradi tional embedded studies. The Commission found that marginal cost-based prices were appropriate for MPC gas. The Commission received testimony that commodity gas would be relatively more scarce than capacity, and adopted a volumetric costing and pricing methodology to promote an efficient market response to the long-term gas shortage and escalating commodity cost. The Commission: 1) found the utility class should not be allocated customer and distribution costs; 2) adopted an inverted rate structure for the firm customer class; and 3) allocated storage costs on a volumetric basis to the interruptible class.

Subsequent to the above dockets, the Commission has re-ceived several retention and incentive rate design filings. A brief description of these filings follow and a more detailed review is provided later in this order. In 1985, MPC filed the first of two versions of an Industrial Market Retention (IMR) tariff (Docket No. 85.7.32). The Commission issued two separate interim orders in this docket. The first, Order No. 5162, granted interim approval of MPC's IMR-85 tariff. A gas price of $3.50/Mcf for large (60,000 Mcf/year) qualifying customers was tariffed. Customers qualified, in part, by submitting a cost-benefit analysis documenting the economics of fuel conversion. The Commission's interim approval required MPC's investors to absorb 10 percent of the differential between the otherwise applicable rate (OAR) and the IMR-85 price.

In June of 1986, the Commission granted MPC's request for interim approval to revise the IMR tariff. The revised IMR tariff, IMR-86, permitted MPC to price down to the "system average cost of gas plus $.50," a potentially lower floor price than existed with IMR-85. Investors still absorbed 10 percent of the differential between the OAR and the IMR-86 price.

In April, 1987, the Commission issued Order No. 5266 (Docket No. 87.3.16) granting interim approval of MPC's proposed Natural Gas Incentive (NGI) tariff filing. The price floor on the NGI tariff allows MPC to price down to the incremental cost of gas. A customer must increase its annual consumption by at least 60,000 Mcf.

In addition, the inverted lifeline-like price structure approved in Docket No. 6618 for the Firm tariff was phased out. In a deferred accounting docket (No. 85.12.52, Order No. 5174), the Commission required MPC to apply a Canadian border price reduction to the tail-block price, returning to a flat annual gas price for firm loads.

On July 31, 1987 MPC filed an application with the Commission for authority to restructure Natural Gas Rates. The IMR and NGI filings, as well as two gas tracking proceedings (and a proceeding for the recovery of the IMR differential) were consolidated into this Docket for final disposition.

Pursuant to a Notice of Public Hearing, a hearing was held in Helena, Montana, commencing on May 17, 1988 and ending on May 18, 1988.

In ongoing Docket No. 88.6.15, and on October 11, 1988, the Commission granted MPC an interim revenue increase of $5,342,220. Prices were increased by a uniform percent to recover the interim increase.

Cost of Service

Introduction. This section examines how costs should be defined for later use in pricing to achieve allocative efficiency objectives. A cost of service model involves numerous steps to arrive at final prices. Table 1 illustrates general costing steps involved in setting prices, and MPC's and MCC's cost and price proposals are reviewed following this model. The costing steps generally involve the first four columns in Table 1 (pricing is the last column). Costs are first sorted by function, and the functionalized costs are then classified based on the product produced, i.e., energy, demand or access. Classified costs are further refined to reflect time of use and pressure of service. Customer classes attempt to efficiently aggregate customers with similar cost characteristics. Each party's costing/pricing analyses fits this general model.

Table 1
A General Cost of Service Model

Costing				Pricing/
Function (1)	Classified (2)	Allocated (3)	Reconciled (4)	Rate Design (5)
Production Gathering Storage Transmission Distribution	Energy, Demand, Customer	Seasons, Peak Days, Customer Classes	Uniform Percent or other e.g., Market Based	$/Mcf/Season $/Month/Access

MPC Cost of Service

MPC's cost of service and rate design witnesses include Mr. Haffey, Dr. Olson, Ms. Schellin and Ms. Wright. MPC's rate design witness is Ms. Orr.

MPC's costing philosophy leads the Company to use marginal costs in determining each class' revenue responsibility. MPC contends that fully allocated costs are irrelevant (MPC Exh. No. 9, p. 8), noting that marginal cost-based prices optimize the use of the economy's scarce resources (MPC Exh. Nos. 9, pp. 5 and 46-50, and Exh. 27, pp. 5-7). The Company states that the marginal cost of service, determined from an "optimal system" study, provides the appropriate costs for pricing purposes (MPC Exh. No. 27, p. 8).

Because marginal costs are not static, several cost issues arise (MPC Exh. No. 9, p. 11). First, the relevant time period is important (i.e., short- or long-run). MPC prefers a long-run approach, as short-run costs will likely fall below average total costs, and sensible system design requires gas systems to have adequate capacity to serve loads during the most extreme weather conditions (MPC Exh. No. 9, p. 15).

Second, the incremental block of output is at issue. MPC sums up its position here by stating that "...it is necessary to think in terms of incremental costs for ratemaking purposes" (MPC Exh. No. 9, p. 17). With the optimal system approach, as described below, MPC bases its marginal cost estimates on an incremental block of output equal to its total system (MPC Exh. No. 9, p. 19).

The third issue involves the development of marginal costs for those costs which are common. MPC states that "Using marginal pricing concepts for a gas utility operation does not make it easier to isolate unit costs" (MPC Exh. No. 9, p. 18). MPC states that costs of increased output for natural gas are incurred on a total increment of production basis, not a unit basis. The above three issues, as resolved by MPC, lay the foundation for the Company's marginal cost approach. Described as the optimal system approach (OSA), MPC's cost approach assumes the utility system is replaced at today's costs and with existing technology (MPC Exh. No. 9, p. 19).

With the OSA, MPC has made certain key assumptions. First, MPC assumed 1985 energy loads would be unchanged into the future. With energy loads assumed to equal normalized 1985 levels, and 1983 peak demand levels, MPC performed cost studies to minimize the total cost of producing and delivering gas for certain cost functions in Table 1 (MPC Exh. No. 9, p. 19). Through various marketing programs, including the IMR, NGI and Smart Choice, MPC is seeking to both retain and attract new loads (TR 33).

A second key assumption is that the OSA accurately measures long-run marginal costs (LRMCs). MPC admits it will never build the optimal system on which costs are based, but states that the actual system evolves toward the optimal system. MPC uses the OSA as a proxy estimate of LRMCs (MPC Exh. No. 9, p. 20).

MPC states that its OSA is consistent with methods employed in electric marginal cost studies, but not the Company's own electric marginal cost of service studies. See e.g. MPC DR PSC No. 3-6, MPC DR PSC No. 1-20iii. MPC's analogy is limited to functionalized transmission and distribution costs, excludes production costs, and does not mention storage costs. MPC cites the methodology used by NERA to compute marginal customer costs, and interprets NERA's methods to reflect an OSA approach (MPC Exh. No. 9, p. 26).

The following discussion reviews MPC's use of the OSA to arrive at class revenue responsibilities. The organization follows the outline in Table 1 above. First, functionalized costs are reviewed, noting assumptions and actual values. This is followed by a discussion of how costs were classified and allocated to classes. A final discussion involves reconciliation.

Cost Functions

Production. Using the competitive market value of gas as a surrogate for actual gas costs, MPC bases its gas production cost estimate on opportunity costs (MPC Exh. Nos. 9, p. 24 and 18, pp. 4-6, 20, TR 105 and MPC DR MCC 1-2). The opportunity cost is the market value, over which MPC has no influence. Thus, MPC's estimate of the market value of gas is beyond MPC's control (MPC Exh. Nos. 9, p. 43 and 18, p. 20). The market value used by MPC is based on an average of three price forecasts.

MPC uses forecast gas costs from three different sources as a proxy for purchased gas costs. MPC's forecast gas supply cost is $2.09/Mcf. According to MPC its average of three cost streams is in real 1987 dollars. The three sources include National Energy Board (NEB), Data Resources, Inc. (DRI) and American Gas Association (AGA) forecasts. MPC's forecast includes costs for years 1987 through 2000 (MPC Exh. No. 18, pp. 3-4).

To calculate a purchased gas cost, MPC averages, in the simplest sense of the word, forecast gas costs (MPC Exh. No. 18, p. 5). The only real dollar aspect is that the costs are deflated by inflation indices before the averaging occurs. MPC used O&M costs for an assumed 100 percent purchased gas cost (MPC Exh. No. 18, p. 19). This differs from the methodology used by MPC to calculate fuel costs, for pricing purposes, in its most recent electric docket addressing this issue (MPC DR PSC No. 2-1).

<u>Optimal Storage And Transmission</u>. Under MPC's OSA approach to computing marginal costs, marginal storage and transmission (S&T) costs are related. The OSA seeks to minimize total S&T costs subject to the constraint that firm loads are reliably served (MPC Exh. No. 18, p. 7). Generally, MPC analyzed the separable and combined total costs of various configurations of pipelines, compressors and storage facilities. Pipeline choices varied by location, diameter and pressure. Storage capacity also varied by location and size (MPC Exh. No. 18, p. 10). MPC applies discounted present value analyses to only two types of costs, carrying charges and compressor fuel (MPC DR PSC 2-5 and 2-7, and MPC Exh. No. 18, p. 7).

MPC performed two levels of analyses. First, MPC looked at storage and transmission costs from three different system load cases: an optimal, average and seasonal. MPC's use of an "optimal" system design is synonymous with its use of an "actual" system (compare MPC Exh. No. 18, pp. 11-13 and Exh. No. 3). MPC used these three load cases to classify and allocate costs as noted below. MPC's "average" case is, in MPC's estimation, a minimum cost scenario which assumes a 100 percent load factor market (MPC Exh. No. 19, p. 10).

The second level of analysis involved alternative S&T designs and investments for each of the above three load perspectives (MPC Exh. No. 18, pp. 8-11). Certain assumptions are key to MPC's analyses of S&T costs. First, MPC used a 1985 market estimate (9/1/86 to 8/31/87) of annual and seasonal firm and interruptible energy loads from a 1986/1987 gas tracker (MPC Exh. Nos. 9, p. 32 and 18, p. 14). MPC's peak loads came from the recent historic system peak of December 23, 1983, and were adjusted for changed contracts and customer additions (MPC Exh. No. 18, p. 16).

Second, and on the cost side, numerous assumptions were made. Based upon an opportunity cost concept, gas in storage was priced at the gas supply cost (MPC Exh. No. 18, p. 3). In contrast to the computation of production fuel costs, MPC discounted costs by means of a net present value (NPV) analysis to compute gas compressor costs (TR 93, 108).

MPC states that storage can allow the Company to forego gas purchases during the entire winter season. In order to optimally size storage, MPC's OSA assumed purchases are made throughout the year at both a 100 percent load factor, and the same price all year (MPC Exh. No. 19, p. 11). MPC explained that the 100 percent load factor is used in computing storage inventory and deliverability requirements as well as gas costs (MPC DR PSC 1-32-i-b).

Distribution. MPC's discussion of how marginal distribution costs were developed is brief (see MPC Exh. Nos. 18, p. 13, Exh. KMS-4 and No. 9, pp. 24, 27). MPC's cost analysis computes the cost to rebuild the entire distribution system using today's technology and costs (MPC Exh. No. 9, p. 26). By this process MPC contends that it has optimized the distribution system design. MPC further contends that this cost approach follows a NERA report which used a minimum system approach (MPC Exh. No. 9, pp. 26, 27). Elsewhere, however, MPC suggested that its distribution cost approach differed from NERA's (TR 41).

In rebuttal testimony, MPC states that a method proposed by the "Gas (sic) utility" and approved in Docket No. 83.9.67 (Order No. 5051d), provides a basis for the proper definition and measurement of marginal distribution and customer costs, and that this method was adopted in the present filing (MPC Exh. No. 22, p. 2). MPC noted that while the optimal system approach was used in this gas docket, the electric utility calculated its original distribution costs by evaluating the investments in distribution plant over the last five years, updating these costs to 1987 (MPC DR PSC 3-6).

Certain assumptions are common across MPC's cost functions, including: 1) 4 percent inflation; 2) MPC's contention that it adopted NERA's approach in computing carrying charges (Exh No. 9, p. 30 and Exh. No. 18, p. KMS-13). The averaging of beginning and end-of-period real economic carrying charges to annualize costs (MPC DR PSC 2-4); 3) 12 percent cost of common equity (per Order No. 5269); 4) 9 percent cost for long-term debt based on prevailing treasury bond rates in April, 1987; and 5) tax rates of 34 percent federal and 6.75 percent state.

Table 2 below summarizes the functionalized costs from MPC's marginal cost study.

Table 2
MPC's OSA Costs
By Function

Function/Sub-Function	Annualized Costs (000 $)	
Production:		
Purchased Gas	57.750	
Other (A&G etc.)	.278	
		58.028
Transmission:		
Carrying Cost	18.013	
O&M	1.059	
A&G	1.141	
Tax (nonincome)	.103	20.300
Storage:		
Carrying Cost	9.134	
O&M	.344	
A&G	.290	
Tax (nonincome)	.036	9.800
Distribution		
Carrying Cost	15.321	
O&M	4.592	
A&G	4.892	
Taxes (nonincome)	.670	
Total Customer Expenses	3.788	29.300
Total Marginal Costs		117

Classified Costs

This section of the order describes how MPC classified costs included in its marginal cost study, the second step in Table

1. MPC's categories for cost classification include: 1) peak demand; 2) winter energy; 3) summer energy; and 4) customer (in this discussion, "access" as used in Table 1 is synonymous with "customer") (MPC Exh. No. 21, pp. 20-24).

<u>Production</u>. MPC classified production costs entirely as energy costs (MPC Exh. No. 21, p. 20).

<u>Storage And Transmission</u>. The method used by MPC to classify S&T costs is complex. Generally, storage costs were classified to two of the four classifications: peak day demand and winter commodity (MPC DR PSC 2-37). Transmission costs were classified to three of the four classifications (MPC Exh. No. 21, p. 21). Ms. Schellin's testimony provides that three sensitivity cost analyses were performed, including an optimal, seasonal, and average system analysis. S&T investment costs from the optimal system case in excess of the seasonal case were then classified as <u>peak-day demand</u> costs. S&T investment costs from the seasonal case in excess of the average case are classified as <u>winter energy</u> costs. Average case costs are classified as summer ($53.293 million), and winter ($113.8 Million) <u>energy</u> costs (MPC DR PSC 2-2).

An example illustrates MPC's classification approach. First, MPC's classification appears similar to the base peak approach used in certain past electric avoided cost dockets (MPC Exh. No. 9, p. 27). In Table 2 above, MPC shows roughly $18 million dollars of transmission carrying costs. Ms. Wright's exhibits show (Exh. No. HAW-6, p. 2) that of this $18 million, about $10.4 million (58%) is <u>winter energy</u> related, $4.9 million (27%) is summer energy related, and $2.8 million (15%) is peak demand related.

The winter energy figure is computed and classified as follows: Looking at data, Ms. Schellin's Exh. KMS-3 and Ms. Wright's Exh. No. HAW-9, Ms. Schellin's exhibit indicates that the average system cost is $136 million, or 68 percent of the optimal system cost of $198 million. Ms. Wright's exhibit shows that 61 percent of annual Mcf volumes are winter related. The product of these two figures is about 42 percent. The differential between the Seasonal cost case and the Average cost case of $31 million ($167 minus $136) is about 15.6 percent of the Optimal system cost of $198 million. The summation of 42 percent and 15.6 percent roughly equals 58 percent. Finally, 58 percent of the $18 million figure for transmission carrying costs roughly equals the $10.4 figure that MPC classifies as winter energy related.

MPC used the resulting ratios to classify certain other types of functionalized transmission costs (MPC Exh. No. 21, p. 21), and storage costs.

Distribution. MPC classified distribution costs as customer, energy and demand related depending on the type of cost (MPC Exh. No. 21, Table HAW-7). As a policy matter, MPC defines customer costs as including the capital, operating, and maintenance costs that vary with the number of customers, regardless of the level of gas consumption (MPC Exh. No. 9, pp. 35- 37). MPC states that this is the same approach for classifying costs to the customer cost category as the Commission approved in Order No. 5051d (Docket No. 83.9.67) (MPC Exh. No. 22, p. 2).

The distribution carrying cost component ($15.321 million in Table 2 above) was classified depending on the type of cost involved. Meters and services were classified as customer related. Network costs, or mains were split evenly between peak demand and energy. O&M related to meters and services, and customer expense accounts is classified as customer related. Other O&M accounts were classified as peak demand related (MPC Exh. No. 21, p. 22).

MPC also contends that all nonpipe costs for a minimum-sized distribution system should be placed in the customer category (MPC Exh. No. 9, p. 35).

Cost Allocation

Cost allocation to seasons and classes is the third step in Table 1. As evident from the above classification section, MPC allocated seasonal energy and peak day demand costs to classes. MPC defines winter to be November through March. Table 3 below summarizes MPC's allocation factors.

Generally, costs which were classified by MPC as energy related were allocated to customer classes based on each class' contribution to each season's total amount of energy consumption (MPC Exh. No. 21, p. 24). An exception was made for energy costs derived from the distribution cost function, which were not allocated to Industrial Interruptible or Firm Utility customers. MPC also lowered the Residential energy consumption by the amount of employee consumption in each season (MPC Exh. No. 21, p. 25). MPC's annual market is based upon normalized actual calendar year 1985 sales, from September 1, 1986 through August 31, 1987.

Table 3
MPC's Allocation Factors
(Energy and Demand Measured in Mcfs at 14.9 PSIA)

Class	Energy (1000) Winter	Summer	Annual	Peak Demand	Weighted Customers
Residential	5,716	3,263	8,979	93,415	88,708
Commercial	3,883	2,123	6,006	66,682	24,220
Ind. Firm	419	339	758	5,714	2,055
Gov. Muni.	647	479	1,126	8,302	571
Firm Utility	3,174	1,534	4,708	48,126	1,072
Interruptible Ind.	2,113	2,532	4,645	0	1,269
Total	15,952	10,270	26,222	222,239	

Source: MPC Exh. Nos. 21, Table HAW-9, and Exh. No. 18, p. 14, and Tables KMS 5, 6. Certain data is found on revised exhibits.

MPC states that the peak demand data in Table 3 are forecast peak day loads (MPC DR PSC 1-13-viii-c). MPC used contributions to the system peak demand to allocate peak demand costs. Peak demand was based on the highest recorded system peak which occurred on December 24, 1983, and, according to MPC, was adjusted for "significant changes since 1983." MPC's cost study allocates winter season storage costs to every class. The interruptible class is not allocated peak day demand costs (MPC DR PSC 2-37). GFG was the only utility that supplied MPC with forecasts of annual and peak day load. MPC reviewed GFG's annual forecast and peak day load data, but only used GFG's annual data in the cost of service study (MPC DR PSC 2-9). Table 3 above provides the number of weighted customers per class, as used by MPC.

Cost Reconciliation

The fourth step in a general cost of service model involves reconciliation. Because MPC is not allowed to earn the level of revenues associated with the results of the above cost study, the results of that study must be reconciled to the total revenues MPC is allowed an opportunity to earn. Table 4 provides MPC's estimated revenue requirement for four scenarios. Column 1 provides the design revenues for each class and the gas utility at the time of MPC's filing (these numbers have changed since the filing). Column 2 provides the marginal cost results of MPC's OSA.

Table 4
MPC's Revenue Requirements
($ millions -- rounded)

Class	Current (1)	Marginal Cost (2)	Equi-Percent Reconciliation (3)	Final Moderated (4)
Residential	35.9	50.8	44.3	40.2
Gen. Service	31.6	36.0	31.3	31.3
Ind. Interrupt.	18.6	14.3	12.4	15.5
Firm Utility	16.4	16.4	14.3	15.3
Total	102	117	102	102

Source: MPC Exh. No. 27, Table JD4-1.

The Company used an equi-proportional approach to reconcile total marginal costs with the allowed revenue requirement (MPC Exh. No. 9, pp. 38, 39). MPC states that this approach best maintains the structure of marginal costs (MPC Exh. No. 10, p. 7). Based only on this adjustment, classes would have the revenue requirement responsibility in Column 3 of Table 4. MPC, however, further moderated revenue impacts as noted in Column 4, by only moving 50 percent toward marginal cost revenue requirements (MPC Exh. No. 27, p. 10).

MPC Rate Design

INTRODUCTION. The last step in a general cost of service study involves designing prices that allow a company to earn its authorized revenues. At present MPC has five retail gas tariffs, including: 1) Firm Natural Gas, for Residential, limited Commercial, Industrial, and certain other loads; 2) Firm Utility Gas Contract; 3) Interruptible Industrial Gas Contract, for customers whose use exceeds 60,000 Mcf/year; 4) Interruptible Market Retention Rate-86; and 5) the Natural Gas Incentive Rate.

The following reviews MPC's current and proposed prices. The prices described below are those in MPC's filing. Due to the lapse of time since MPC's filing and subsequent price changes, the current prices noted below differ from those tariffed today.

Residential. Residential customers are served on the Firm Natural Gas tariff, which features a $3.359/Mcf price. MPC proposes a gas price of $3.494 and a Customer Charge of $3.85.

General Service. Commercial customers are served on the Firm Natural Gas tariff and also pay $3.359/Mcf. MPC proposes a nonlinear declining-block price structure. The first 1,000 Mcf would be sold at $3.511/Mcf, and any additional Mcf would be charged at $2.939/Mcf. MPC states the 1,000 Mcf blocking was a judgment call, that no precise cost justification explains the $.572/Mcf differential, and that the differential appears to reasonably define the break between small and large users (MPC DR GFGC 1-13 and MPC DR MCC 2-8). A Customer Charge of $8.25 is proposed.

Firm Utility. The current Mcf price is $3.340. MPC proposes a $3.257 price, and no other rate elements.

Interruptible Industrial. The current tariff features a commodity price of $3.87/Mcf. The proposed tariff features a $3.299/Mcf commodity price and a Customer Charge of $1,570 per month.

Industrial Market Retention. Interim Order No. 5162, granted approval of MPC's IMR-85 tariff. This tariff, offered gas at $3.50/Mcf for large (60,000 Mcf/year) qualifying customers. Customers qualified, in part, by submitting a cost benefit analysis documenting the economics of fuel conversion. The Commission's approval required MPC's investors to absorb 10 percent of the differential between the OAR and the IMR-85 price. The remaining difference is recovered via the unreflected gas cost tracking mechanism.

Subsequently, the Commission granted MPC's request for interim approval to revise the IMR tariff. The revised IMR tariff, IMR-86, permitted MPC to price down to the "system average cost of gas plus $.50," a value potentially lower than the prior $3.50 floor price. Investors still had to absorb 10 percent of the OAR less IMR-86 price differential. The remaining difference is recovered via the unreflected gas cost tracking mechanism. MPC contends that the recovery of the differential should not be considered a business risk its shareholders should absorb (MPC Exh. No. 28, p. 7).

Natural Gas Incentive. Interim Order No. 5266 (Docket No. 87.3.16) granted approval of MPC's NGI tariff filing. To qualify, an existing customer must increase its load by 60,000 Mcf, while a new customer must have a total load exceeding the same amount on an annual basis. To encourage demand, the price floor on the NGI tariff allows MPC to price down to the marginal cost of gas plus nongas costs. Contracts which establish the agreed upon price are renewed annually with customers. If the alternative fuel price eventually exceeds the otherwise applicable tariffed rate, then the latter substitutes for the NGI price. The actual sales price will vary by customer. The tariff is structured so that the customer served pays the entire cost of any needed line extension service facilities (MPC DR PSC 1-11 in Docket No. 87.3.16). On an interim basis, the Commission denied MPC's request to flow through 10 percent of the difference between the NGI price and the incremental cost to its shareholders.

IMR and NGI. Other aspects of these two tariffs are as follows: First, one difference between the two tariffs regards MPC's planned sunset. MPC initially stated the IMR is a short-term experimental rate, but later proposed to make the IMR permanent

(MPC DR PSC 1-11 in Docket No. 85.7.32, and MPC Exh. No. 27, p. 16). In contrast, MPC stated that NGI contracts (assumably availability) are limited to three years and expire on April 21, 1990 (MPC DR PSC 1-8-i-c, 1-31-v-a and 2-35). In April, 1990, MPC intends to review the merit of continuing the NGI tariff (TR 186); Second, service on both tariffs is interruptible; Third, the 60,000 Mcf threshold logic is similar for each tariff, and stems from the historical level used to establish the availability criteria for the IIGC tariff (MPC DR MCC 3-5 and 3-8).

<u>Intervenor Testimony</u>

<u>MCC Testimony</u>

The MCC employed J.W. Wilson and Associates to provide marginal cost analyses and pricing testimony. Mr. Jim Drzemiecki testified on MCC's behalf. MCC expressed concern that prices reflect economic costs so as to minimize resource misallocations, an objective MPC fully embraced. MCC, however, differs with MPC on how costs should be functionalized, classified and allocated. Importantly, MCC disagrees with MPC's OSA in that, as a practical matter, it would probably take at least 20 years to restructure a natural gas supply system from the ground up (MCC Exh. No. 36, p.

16). The following is a review of MCC's cost of service and rate design testimony.

Philosophically, MCC embraces the concepts of economic efficiency in its testimony. MCC's cost and price analysis used an interim revenue requirement of approximately 102 million dollars established by the Commission in Order No. 5245 (MCC DR MPC No. 5). For inter- and intra-class revenue requirement allocations, MCC states that a marginal cost study is relevant. MCC stresses that prices should reflect long-run marginal costs (MCC Exh. No. 36, pp. 12, 17).

MCC's testimony is reviewed in the same order as that for MPC above. In turn, functionalization, classification, allocation, reconciliation and pricing is discussed.

Cost Functions

MCC functionalized costs into three general areas: Gas Supply, Distribution and Customer Service. Gas Supply, which is reviewed next, has three sub-functions: Gas Purchase, Storage and Transmission (MCC Exh. No. 36, pp. 25-26).

<u>Gas Supply</u>

<u>Gas Purchase</u>. MCC's general approach to measuring and valuing gas purchase costs is similar to that used by MPC. However, MCC's approach used more recent field acquisition costs from one source, a 1988 American Gas Association price forecast. MCC computed a gas purchase price of $2.43/Mcf using a simple average of 18 years of forecast AGA gas prices (1988 dollars) (MCC Exh. No. 36, p. 41). Ms. Schellin criticized MCC's analysis for not using consistent 1988 dollar estimates for all cost functions. MPC also challenged MCC's $2.43/Mcf gas purchase cost for not including certain costs (A&G etc.) (MPC Exh. No. 22, p. 3).

<u>Storage and Transmission</u>. While discussed separately below, MCC focuses on the added cost of gas supply capacity. Capacity costs are the costs incurred to have adequate capacity for additional system peak demands (MCC Exh. No. 36, p. 31). For reasons noted later, MCC stated that the proper measure of marginal storage and transmission is the cost associated with connecting the lowest-cost capacity to the existing system to meet peak and seasonal loads (MCC Exh. No. 36, pp. 32-33). As support for its approach taken in this docket, MCC cited to a previous Commission

order (MCC DR MPC 10). Table 5 below breaks down MCC's proposed S&T costs.

Table 5
MCC's Storage and Transmission
Cost Development

	Storage	Transmission
1) Compression Plus Wells Capital Investment	$74.27/Mcf	
2) Transmission Line Capital Investment		$219.25/Mcf
3) Horsepower		43.61
4) Gas In Storage	2.43	
Sub Total	76.70	262.86
5) Annualized Cost/Mcf	7.70	23.79
6) Fixed O&M	1.54	4.72
Total	$ 9.24/Mcf	$ 28.51/Mcf

Source: See MCC DR MPC 12 and MCC Exh. No. 36, Exh. J.D. 1.

Storage. MCC's storage costs include additional peak period and winter season costs. MCC states that for ratemaking purposes, the marginal cost of storage is the cost associated with the addition of the least-cost storage capacity sufficient to meet additional peak and seasonal loads from the existing storage system (MCC Exh. No. 36, p. 32). Peak demand costs would never exceed the annual carrying cost of added capacity with the lowest fixed cost per Mcf of capacity (MCC Exh. No. 36, p. 31).

With the above approach, MCC's second gas supply sub-function uses storage costs derived from MPC's cost study. MCC's estimated marginal storage cost is $9.24/Mcf, in 1987 dollars (MCC Exh. No. 36, Table JD-1, p. 3). MCC included in its study the costs for storage compression, wells facilities and gas in storage. MCC chose to exclude "storage facilities investment" in its marginal cost study, noting the Company has adequate storage capacity (MCC Exh. No. 36, p. 40). The MCC also states that Gas Storage costs are incurred to avoid Gas Purchase costs during the peak season (MCC Exh. No. 36, p. 32).

Ms. Schellin rebutted MCC's analysis for failing to reflect the cost of: 1) "incremental storage inventory;" and 2) the cost of a pipeline to connect the storage field to the transmission system. MPC's estimate of incremental storage costs that MCC should have included equals $45.87/Mcf, which should be added to the $9.24 figure above. MPC's $45.87 figure represents 188/Mcf of storage inventory capital investment ($456.84 annualized with a 10.04 percent carrying charge). The 188 Mcf amount is the required investment in reservoir pressure to force 1 Mcf from the storage reservoir to the compressors on peak day (MPC Exh. No. 19, p. 12). With Ms. Schellin's proposed changes, MCC's total incremental storage gas costs would rise by roughly $7.7 million per year (MPC Exh. No. 22, p. 6).

Transmission. MCC's final Gas Supply sub-function involves transmission costs. MCC's estimated marginal cost equals $28.51/Mcf in 1987 dollars (MCC Exh. No. 36, Table JD-1, p. 2). MCC noted the transmission system serves to provide system reliability and peak capacity. MCC states that a proper measure of the marginal cost of transmission is the cost to connect the least cost capacity addition to the existing system to meet peak load (MCC Exh. No. 36, p. 33).

MCC developed marginal transmission costs based on three of MPC's transmission line segments which supply over 50 percent of the total peak demand. These lines included: 1) the Shelby-Great Falls; 2) Missoula Tap-Missoula; and 3) Missoula Tap-Butte Tap. MCC also used the cost of "transmission horsepower facilities" for the Dry Creek facilities from MPC's cost study, which includes pumping costs to move gas over the transmission system (MCC Exh. No. 36, pp. 39-40 and MCC DR PMCC-18).

Dr. Olson rebutted MCC's approach claiming that MCC's analysis does not reflect true marginal costs, uses only portions of the necessary storage and transmission facilities, and excludes distance as a pertinent factor (MPC Exh. No. 10, pp. 4-5). Ms. Schellin further argued that MCC's analysis is flawed by virtue of the fact that MCC unitized costs by simply dividing the costs for the above noted line segments by their peak day flows. She added that the peak day flows were erroneous, and even if correct the analysis was still flawed: the cost of each line varies more with respect to its length than peak day flow (MPC Exh. No. 10, pp. 9-10). Ms. Schellin also contended that MCC understated transmission horsepower costs: By dividing MPC's estimated investment in redundant horsepower on the southern end of the optimal system by peak day Mcf's, MCC understates this portion of transmission costs as the associated investment was not designed to carry total system requirements (MPC Exh. No. 19, pp. 10-11).

Ms. Heidi Wright criticized MCC's gas supply cost analysis for not including certain related expenses such as A&G, general and common plant, intangible plant and working capital for production, transmission and storage functions (MPC Exh. No. 22, p.

3). There is over fifteen million dollars per year difference between MCC's and MPC's estimate of marginal storage costs (MPC Exh. No. 22, p. 5).

Distribution and Customer

As its source of distribution costs MCC used MPC's total investment in distribution mains and other noncustomer facilities related costs (MCC Exh. No. 36, p. 43). That is, MCC used embedded distribution costs as proxies for long-run marginal costs (MCC Exh. No. 36, p. 46).

MCC describes its development of customer charges to reflect its customer costs as follows:

> Customer charges contained in the rates are based on customer costs as quantified in my cost study. Since each rate class' monthly customer cost, except Interruptible class, exceeded MPC's proposed charge, I utilized MPC's proposed customer charge for these classes. The customer charge for this class was set equal to one based on my computation of customer costs. (MCC Exh. No. 36, pp. 7-8.)

With regard to the issue of optimal line extension policies, MCC states that the costs of a new service drop, or of extending the existing distribution system, are costs that are properly allocated to the new customer (MCC Exh. No. 36, pp. 27-28).

Dr. Olson rebutted MCC's approach as not being consistent with MCC's own costing philosophy endorsing marginal costs (MPC Exh. No. 10, p. 3). Further, Dr. Olson argued that marginal customer and distribution costs are just as important as gas supply costs, serving to prevent or discourage uneconomic investment (MPC Exh. No. 10, pp. 11-12).

Cost Classification

MCC's cost functions include gas supply, distribution and customer functions. The gas supply function, in turn, has three sub-functions which include gas purchases, transmission and storage.

MCC classified Gas Supply costs as follows: First, purchased gas costs were classified as energy related; Second, gas supply storage and transmission costs were classified as energy and peak day demand related (MCC Exh. No. 36, p. 51). MCC states that this split is based upon logic similar to that used by MPC (MCC DR PMCC-13). MCC states that its position follows from the results of MPC's classification of plant. For example, MPC classified about 85 percent of transmission plant as commodity related, while MCC classified about 88 percent of transmission costs as commodity related (compare MPC Exh. No. 21, Exh. HAW-6, with MCC Exh. No. 36, Exh. J.D.-2). However, MCC's storage classification clearly differs from that of MPC.

Distribution costs were split evenly between commodity and demand. MCC classified one-half of the investment in distribution mains and noncustomer facilities as demand-related and the other half as energy-related (MCC Exh. No. 36, p. 45). Finally, customer costs are classified as customer-related. MCC's methodology used to compute distribution costs does not result in "unit" cost figures, but rather derives total costs split out by classification. MCC argued that because the distribution system must be designed to meet noncoincident maximum demands as well as the average commodity requirements of MPC's customers, the distribution system costs should be classified to reflect their energy and peak demand functions (MCC Exh. No. 36, p. 45). MCC agreed that a distribution system designed to meet noncoincident maximum demands is sufficient to meet the average commodity requirements (MCC DR PMCC-19).

MPC challenged MCC's distribution cost analysis. Ms. Wright noted that MCC's classification of one-half of the investment in the noncustomer portion of distribution plant is the same approach MPC used despite MCC's claim to the contrary (see MCC Exh. No. 36, p. 44 and MPC Exh. No. 22, p. 8).

Cost Allocation

At this point, MCC's costs have been identified and functionalized as either gas supply, distribution or customer related. These functionalized costs were then classified as either energy, capacity or customer related. The allocation of costs involves all cost functions and classifications, and costs are first allocated to seasons and then classes. MCC's allocation of classified costs differs from that used by MPC.

MCC allocated gas supply costs as follows: First, purchased gas costs were allocated based on each class' respective share of MPC's annual load; Second, transmission commodity costs were allocated to each class based on each class' annual Mcf energy load. Storage commodity costs were only allocated to all winter loads (MCC Exh. No. 36, p. 51); Third, transmission and storage demand costs were allocated to classes based on each class' contribution to MPC's estimated system peak demand (see MCC DR MPC 40, and MPC DR to MCC 1-5 and 2-3); Fourth, customer costs were allocated to classes using each class' weighted percent of the total number of customers (MPC Exh. No. 36, Tables JD-2, JD-3).

The above allocations include the utilities' and interruptible customers' commodity and demand loads; Finally, MCC allocated distribution commodity and demand costs using the same approach as for transmission and storage (MCC Exh. No. 36, p. 45), except MCC excluded the contributions to total annual commodity and annual peak demand made by the utility and interruptible loads (MCC Exh. No. 36, Tables JD-2, JD-3).

In developing and allocating demand costs, MCC did not use a consistent system peak demand. When developing unit S&T costs (in Table 5), MCC used 224,139 peak Mcf. To classify total S&T costs MCC uses 193,422 Mcf. The latter figure was also used to allocate costs.

MCC thoroughly discussed, but did not propose, tariffing seasonal gas prices. MCC stated that prices must include a capacity price signal to efficiently constrain peak demands, and that variations in costs to purchase or acquire gas should drive the decision to tariff seasonal prices (MCC Exh. No. 36, p. 30). In this regard, MCC concurs with MPC that Gas Supply costs vary by season and that the higher cost winter season includes November through March (MCC Exh. No. 36, pp. 5 and 36).

Dr. Olson rebutted MCC's allocation of transmission and storage costs to interruptible customers as leading to discriminatory ratemaking, since interruptible customers are allocated the same costs as firm customers for different service (MPC Exh. No. 10, p. 9). Ms. Schellin criticized MCC's use of a 1985 system peak (MPC Exh. No. 19, p. 7). Mr. Jan Michael, on behalf of Stone Container, also rebutted Mr. Drzemiecki's allocation of capacity costs to interruptible customers. Mr. Michael stated that interruptible service is different from firm service, and that firm service should be priced at a premium. Stone Container does not have any expectation of receiving utility service on peak day (SCC Exh. No. 35, pp. 2-6).

Cost Reconciliation

MCC's reconciliation approach equates total marginal costs to the embedded revenue requirement by increasing gas supply costs only, the costs which MCC believes are the most important marginal cost functions (MCC Exh. No. 36, p. 47). Dr. Olson rebutted MCC's reconciliation approach as resulting in embedded costs for the gas supply function (MPC Exh. No. 10, p. 3).

MCC also proposed to moderate cost allocation impacts that resulted from its cost study (MCC Exh. No. 36, pp. 7 and 52), by proposing to increase the residential class' revenue requirement by 5.75 percent, one-third of the cost-justified increase. To maintain revenue neutrality in this docket, MCC proposed price reductions to accommodate the proposed increase to the residential class. The errata to MCC's testimony explains its proposed price reductions:

> First, the revenues for the Government and Municipal and Utilities will be reduced by an amount sufficient to reduce the differential between the revenues and costs to the same 6.2 percent that exists for the industrial firm. Interruptibles will receive the remainder of the differential. (MCC Exh. No. 38.)

For moderation purposes MCC separated the Government and Municipal classes from the Commercial class. MPC does not have separate Government and Municipal tariffs, but MCC proposes to lower these customers' revenue requirements, while freezing the revenue requirements for the balance of the "Commercial" class. MCC proposes to reduce all but the Commercial class' revenue requirement by the amount of the increase to the residential class (MCC Exh. No. 36, pp. 52-53). Mr. Haffey rebutted MCC's revenue moderation proposal as result oriented, and not recognizing MPC's obligation to all of the customer classes (MPC Exh. No. 28, p. 2). Mr. Michael also criticized MCC's approach to moderation, noting that it would further increase existing class cross-subsidies between the residential and interruptible class. According to Mr. Michael, this was contrary to Mr. Drzemiecki's costing philosophy, and resulted in inappropriate income redistribution (SCC Exh. No. 35, pp. 7-10).

MCC Rate Design

As with the MPC's rate design proposals reviewed earlier, MCC's prices described below are the prices and revenue requirements at the time of filing. As noted, the allowed revenue requirement has changed.

Residential. Residential customers are served on the Firm Natural Gas tariff which features a $3.359/Mcf price. MCC proposes a gas price of $3.277 and a Customer Charge of $3.85. MCC proposes separate prices for employees (MCC Exh. No. 36, JD-4, p. 1). MPC discounts each employee's total bill 25 percent (MPC DR PSC 1-1).

General Service. Commercial customers are currently served on the Firm Natural Gas tariff and also pay $3.359/Mcf. Initially, MCC concurred with MPC's proposed nonlinear declining-block price structure (MCC Exh. No. 36, p. 54). In revised testimony offered at hearing, MCC changed its proposal to suggest that a flat commodity price of $3.307/Mcf would be appropriate, with a Customer Charge of $8.25.

Firm Utility. The current Mcf price is $3.34. MCC proposes a $3.303 price, and no other rate elements.

Interruptible Industrial. The current tariff features a commodity price of $3.87/Mcf. MCC's proposed tariff features a $3.775/Mcf commodity price and a Customer Charge of $1,120 per month.

IMR and NGI. MCC finds neither tariff's current form acceptable and strongly recommends that the Commission defer a final order on cost and benefit sharing for these two tariffs until MPC's next general rate case. This is to insure that the business risk remains a responsibility of MPC's shareholders, and to allow the Commission an opportunity to review the present distribution of costs and benefits (MCC Exh. No. 36, pp. 8-9, 61-62, and MCC DR MPC 22). If the Commission finally approves the IMR tariff out of the present docket, and until such time as MPC files a general rate case, MCC recommends continuation of the 90/10 risk sharing with the IMR tariff (MCC Exh. No. 36, p. 62). Similarly, MCC recommends the continued flow through of NGI benefits to other ratepayers, with final consideration in the next general rate case, not a tracker. MCC recommends changing the recovery method for the 90/10

IMR risk sharing from a tracker to a general rate case (MCC Exh. No. 36, p. 60).

To insure that discounted prices cover incremental costs so as to avoid adverse impacts on nonparticipants, MCC recommended the Commission require MPC to file the following material: 1) incremental revenues per month from each tariff; 2) monthly incremental capacity and commodity costs per customer, and customer costs to serve loads under each tariff; and 3) an annual report of all direct and indirect investments made by MPC to provide service under each tariff (MCC Exh. No. 36, pp. 58-59).

Great Falls Gas Testimony

On behalf of GFG, Mr. Geske and Ms. Cheryl Beach testified on certain cost of service and rate design issues. The thrust of GFG's testimony is to lower the Firm utility gas price below that MPC proposed. GFG did not submit a thorough cost study, but supports marginal cost based prices (GFG Exh. No. 32, p. 5).

Mr. Geske's testimony focuses on three issues. First, GFG opposes MPC's recovery of IMR costs through a deferred gas cost docket. GFG also opposes MPC's recovery of any IMR costs from transmission level customers such as GFG. If MPC's distribution and transmission systems were independent of one another, GFG would not be burdened with any IMR costs (GFG Exh. No. 30, pp. 3-4). Second, GFG objects to the moderated price decrease to Firm Utility loads, stating that a 50 percent moderation is inadequate (GFG Exh. No. 30, p. 5). Third, GFG contests MPC's peak-day contribution assigned to GFG (GFG Exh. No. 30, p. 6), arguing that it overstates GFG's load.

Ms. Beach elaborates further on issues raised by Mr. Geske. Ms. Beach's testimony covers four issues: 1) MPC peak demand estimates for GFG; 2) MPC's long-run gas cost estimate; 3) recovery of IMR revenue deficiencies from classes whose prices exceed marginal costs; and 4) rate moderation (GFG Exh. Nos. 32, 33).

First, Ms. Beach contends that MPC's peak-day contribution to the system peak demand for GFG is excessive. Ms. Beach proposed that MPC lower GFG's contribution to peak day demand 12 percent to reflect both the MAFB peak-day load loss, and new interruptible loads (GFG Exh. Nos. 5, 32, 33, pp. 4-5). MPC used 41,943 Mcf of peak demand for GFG. MPC did adjust certain of the utility's loads to reflect changes in the number of customers (MPC Exh. No. 19, p. 7). Ms. Schellin rebutted Ms. Beach, stating that any errors in peak demand for GFG result from GFG's own estimates. Ms. Schellin declined to adjust GFG's peak demand to reflect changes in load for GFG's estimate of the Malmstrom peak load reduction, perceived conservation impacts, and new interruptible loads (MPC Exh. No. 19, p. 5). She did not perceive these adjustments to be consistent with other peak day load adjustments for similar customer classes on the MPC system. There was no contractual basis to support the adjustments and assure that there was no responsibility for MPC to provide service (MPC Exh. No. 19, pp. 5-6).

Second, Ms. Beach contests the time frame used by MPC to compute purchased gas costs, and recommends using 1989 gas costs in place of MPC's long-run marginal costs. Ms. Beach argues that because MPC's average gas cost for 1989 is $1.53/Mcf, and MPC's $2.09/Mcf value does not reflect future border gas prices until 1993 or 1994, MPC's proposed figure of $2.09 should be lowered to $1.53/Mcf (GFG Exh. No. 32, pp. 7-8). Dr. Olson rebutted Ms. Beach's proposal, arguing that her objective is essentially result-oriented and that it is inappropriate to base gas prices on short-run costs (MPC Exh. No. 10, pp. 1-2). Ms. Schellin also challenged Ms. Beach's $1.53 figure, adding that if it were revised to reflect

Ms. Beach's preferred embedded cost perspective it would rise to $2.20/Mcf (MPC Exh. No. 19, p. 2). Ms. Schellin further noted that Ms. Beach has not analyzed the impact on "storage rate base" of a lowered purchase gas cost assumption (MPC Exh. No. 19, p. 4).

Third, Ms. Beach states that the IMR revenue deficiency should not be recovered from classes paying more than their marginal cost based revenue requirement, as this would be moving rates in the wrong direction (GFG Exh. No. 32, p. 12). Ms. Heidi Wright found the Firm Utility class' marginal cost revenue requirement to equal $16.4 million, a figure which nearly equals the same class' current revenues of $16.345 million (MPC Exh. No. 21, p. 3). Mr. Haffey rebutted GFG's proposal, noting it is unfair to other customers to not share in these costs (MPC Exh. No. 28, pp. 2-3).

Finally, Ms. Beach argued that rather than MPC's 50 percent, a move toward reflecting 75 percent of moderated revenues is appropriate. Her studies showed that the utility class is paying at least 13.0 percent, and possibly 17.0 percent, more than marginal cost (GFG Exh. No. 32, pp. 9-10). Accordingly, a revenue requirement reduction of 12.70 percent was appropriate. Mr. Haffey rebutted GFG's proposal, and supported MPC's 50 percent proposal

(MPC Exh. No. 28. pp. 1-2). Mr. Michael criticized Ms. Beach's approach, noting that it was inappropriate to single out one class for cost-based rates while continuing large cross-subsidies among the other classes (SCC Exh. No. 35, pp. 10-11).

Shelby Gas Testimony

Mr. Larry Nelson testified on behalf of the Shelby Gas Association. Mr. Nelson requests that MPC be required to lower prices to the Firm Utility class by 12.37 percent, consistent with its cost study (SGC Exh. No. 31).

Stone Container Corporation Testimony

Mr. Jan Michael testified on Stone Container's behalf. The thrust of Mr. Michael's testimony (hereafter SCC) is to support MPC's IMR tariff. SCC did not submit its own cost of service study, and used MPC's cost analyses to illustrate rate impacts. SCC did not endorse MPC's long-run marginal cost study (SCC Exh. No. 34, pp. 2, 10), but noted a preference for embed ded cost studies. SCC stated that the Interruptible Industrial revenue requirement is too high, based on a comparison to MPC's long-run marginal costs (SCC Exh. No. 34, pp. 3-5). SCC also contends that the IMR rate is not subsidized (SCC Exh. No. 34, pp. 5-7). It supported this position by its computation of the "benefit," contribution to fixed costs of the IMR, of $1,314,277. SCC points out that if it left the MPC gas system other customers would have to recover an additional $2,976,437 in fixed costs (SCC Exh. No. 34, pp. 7-10).

SCC disagrees with MPC's OSA based marginal cost study, arguing that embedded and marginal cost revenue requirements are not equal. SCC concludes that the Commission should carefully review the results from MPC's OSA (SCC Exh. No. 34, p. 11).

PART II

Commission Decision

The Commission's decision is this docket is lengthy and complex, reflective of the issues raised by the various parties. The decision is organized as follows. First, the cost-of-service model in Table 1 shall serve to organize the Commission's decision. Following a brief commentary on the relevant cost perspective, the decision will discuss in order: cost functions, classifications, allocations and reconciliation.

Cost Perspective

Traditionally, embedded cost of service studies determined each class' individual cost responsibility and prices. More recently, Commission policy has not applied embedded cost studies for the above purposes. The underlying reasoning is efficient resource allocation. The alternative costing approach embraced by this Commission involves marginal cost pricing.

From a policy standpoint, the Commission is in accord with GFG, MCC and MPC on the use of a marginal cost analyses to determine prices. As MPC states, it is the economy's or society's costs that are relevant to marginal costs (MPC Exh. No. 9, p. CEO-43). MCC also stated that because the use of marginal costs leads to a rate structure which meets the objectives of encouraging conservation, efficiency and equity, marginal costs should determine inter- and intra-class revenue requirements (MCC Exh. No. 36, p. 13). The parties differ on how to compute marginal costs.

The Commission notes that this is the first time it has received comprehensive marginal cost analysis for a gas utility. Further, it is the first occasion before this Commission that the issue has been debated with any rigor.

Cost Functions

Production. Production costs comprise the major share of marginal cost revenue requirements. For this reason, there is relatively more discussion on this issue. Several methods were proposed regarding the relevant perspective to compute gas production costs, including short- and long-run marginal costs (SRMC and LRMC). GFG proposed a gas cost estimate of $1.53/Mcf. MPC and the MCC agree that a LRMC perspective is most relevant, adding that the market value of gas is the proper source for making this estimate. A market value method raises the concept of opportunity costs (TR 104). Opportunity costs are also reflected in electric marginal costs. MCC and MPC disagree on the best source(s) for this cost basis.

The Commission finds merit in MPC's and MCC's LRMC perspective for computing the cost of service for firm loads. The LRMC perspective is premised upon the welfare economics position that pricing at LRMC over all short-run periods creates net economic benefits. MPC's witness Dr. Olson stated it is not appropriate to base gas rates on SRMC and that the SRMC pricing principle must be compromised with the interest of practicality (MPC Exh. Nos. 10, p. 5 and No. 9, p. 14). This result contrasts with MPC's pricing philosophy for its IMR and NGI tariffs (TR 44-46).

Issues that arise with the development of production LRMCs with either MPC's or MCC's approach include: 1) the source of costs; and 2) the method used to levelize costs. Recognizing the difficulty of forecasting the Commission finds MPC's average of three sources superior to MCC's single source. Inherent in using more than one source is forecasting stability resulting from diversity. The Commission also finds merit in updating MPC's AGA data to reflect MCC's more current AGA cost data.

Second, neither MPC's or MCC's method accords with what is done in electric cost of service studies for cost levelization. For gas marginal production costs MPC and MCC both levelize by averaging a time series of deflated costs. Thus, the only factor by which future gas costs are brought back to the present is the assumed rate of inflation. The Commission intends to thoroughly investigate the merit of using deflated or real-levelized costs in MPC's next gas cost of service docket.

Some issues the Commission intends to investigate include: 1) MPC's claim that carrying charges are used as discount rates; 2) MPC's reference to carrying charges applied to investments; 3) MPC's use of AGA, DRI and NEB gas data sources in comparison to the calculation of electric marginal energy cost using BPA NR data; 4) the concern that costs will be "understated"; 5) the Company's own use of real levelized gas costs, real levelized electric avoided and retail costs relative to its reluctance to seek consistency in this docket; and 6) the Company's preference for real levelized gas capital costs which must rise at the rate of inflation versus the deflated dollar choice for gas costs.

The Commission's decision on computing the opportunity cost of gas follows. First, whereas MPC used 1987 through 2000 data, the Commission believes the first two years (1987 and 1988) should be dropped, and two years added. See MPC DR PSC No. 2-1-iii. Thus, 1989 through 2002, or 14 years of data will still be used. In addition, all costs will have to be adjusted to mid-year 1989 dollars, a change that will not directly impact the revenue requirement, but does impact the value of the commodity gas (MPC DR PSC 1-29-ix). Historic market values do not bear upon prospective efficient resource allocation.

Second, the current year dollar values for MPC's three gas sources are obtainable from MPC's testimony (MPC Exh. No. 18, unrevised Table I-B). The stream of average gas cost data in this table is in current year dollar terms, as MPC used a nominal 10.5 percent discount rate to compute the net present value figures on this table (MPC's revised version of this data actually defines a "nominal" cost stream, but the three sources of data are not separately reported).

As noted above, the Commission finds MPC's data must be modified to reflect a year for year replacement of MPC's older AGA data with MCC's more current data. MCC indicated that the only advantage its single AGA data source has over averaging is that it is more recent (MCC DR PMCC-15). Because MCC's AGA data is in 1988 dollars, it must be inflated and converted to mid-year 1989 dollars using MPC's assumed 4 percent inflation rate.

The Commission finds a final adjustment to the cost of gas production is needed to reflect MPC's estimate of use and line losses, similar to that done in electric rate cases. Conflicting information arose in this docket as to the levels of use and line losses and the actual values. The Commission will review use and line losses from three different MPC sources. First, information derived from a 1987 MPC Gas Utility Business Plan indicates that MPC computes three levels of use and losses: 1) gathering; 2) distribution; and 3) transmission (MPC DR PSC 1-13-ix, page 11 of 21). From this source MPC appears to incur a use and line loss of approximately <u>11 percent</u> to deliver gas to the distribution level.

Second, in contrast to the above, MPC assumed a transmission use and loss factor of about 3.5 percent (MPC Exh No 18, Exh KMS-5). From the same source, distribution use and line losses roughly equal 1.6 percent. The combined use and line loss equals approximately <u>5.2 percent</u> at the distribution level. However, MPC stated that the above use and loss adjustments reflect actual values, which may not equal optimal values (MPC DR PSC 2-8-iii).

Third, for years 1983 through 1987, MPC's actual use and line loss averaged 100 percent greater than the 5.2 percent level (MPC DR PSC 2-8). That is, MPC's actual historic experience appears to run around 11 to 12 percent, as used in the Gas Utility Business Plan. The Commission intends to address these inconsistencies as well as any storage related use and losses in MPC's next gas cost of service study.

With the above transmission and distribution cost of service, one can compute the associated marginal cost revenue requirement for each class except for the IMR and NGI loads. When doing so, MPC must assume the residential, Government and Municipality, and commercial loads are served at the distribution level of service, and all others at the transmission level, with the following exception: when submitting its compliance filing in response to this order MPC must factor in the assumption that 16 percent of its Interruptible Industrial loads are served at the distribution level of service. See MPC DR GFGC 1-31, and the Company's 1987 Gas Utility Business Plan (MPC DR PSC 1-13-ix, p. 11 of 21). This 16 percent figure will be scrutinized in MPC's next cost of service docket.

A final comment concerns GFG's proposal to use $1.53/Mcf for determining the cost of service. Although an obvious shortcoming is that the proposed embedded cost based price is not efficient for resource allocation over the long run, GFG did not perform a complete cost study. Clearly, the production cost is not the only avoidable cost.

MPC's Optimal System Approach. The Commission will first address the merit of MPC's optimal system approach. The testimony of both MPC and MCC supports marginal cost pricing. Marginal cost pricing can take on different dimensions, one of which is MPC's OSA. While the Commission lauds MPC for recognizing the import of marginal costs, the Commission has serious reservations about the enhanced efficiencies resulting from applying the OSA to pricing policies which impact resource allocation.

The Commission's substantive reasons for rejecting MPC's optimal system approach fall into the following areas: 1) the OSA does not reflect avoidable costs; 2) MPC's actual investment plans and its OSA investment plans are not similar for distribution, storage and transmission investments; 3) discounting is required to properly compute avoided costs; and 4) MPC's testimony is inconsistent on the merit of an OSA in costing versus the merit of the OSA in rate design. The OSA is more accurately described as a reproduction cost model, not a marginal cost study. Although it may be argued that this approach is valuable because it captures many of the benefits associated with long-run marginal cost, such as technological change, the Commission finds that a study that relies entirely on a fictitious system does not result in an adequate proxy for long-run marginal cost. As noted below, measurement of the marginal investment costs related to an increase or decrease in peak day demand (for example), requires the use of the existing system as a point of departure. Although the OSA could be used to generate the costs associated with increments in capacity, it is also clear that these figures derive from the expansion of a conceptual "optimal system," not MPC's current system. The Commission also finds MPC's "system growth" argument, as a basis for adopting the OSA, to be inapposite: if avoidable costs in fact do not exist, the Commission believes it is not appropriate to pretend that such costs exist, only for the sake of having them. Further, and on balance, the Commission finds that its other concerns with the OSA far outweigh any possible relevance that the existence or nonexistence of system growth may have for this analysis.

First, although MPC concedes the relevance of avoided costs in cost of service studies (TR 29), the OSA does not pass the "avoided cost" acid test. That actual avoided costs, and not hypothetical OSA costs, are of import is evident from MCC's testimony, which states the most operational and conceptual framework for the definition of marginal costs is the cost of "adding inputs" to the existing utility system (MCC Exh. No. 36, p. 14). If costs are not based on actual inputs added, cost avoidance is not possible. Even MPC's Dr. Olson noted that the evolution of MPC's system toward the OSA would occur incrementally (TR 19). The OSA reflects a changed costing philosophy on MPC's part relative to cost of service studies submitted to this Commission, including that by NERA on MPC's behalf in Docket No. 80.4.2 (MPC DR PSC 1-20).

Second, the Commission believes that MPC's OSA based costs do not reflect avoidable costs. While one of the Company's witnesses described as "dubious" the fact that the average remaining life of MPC's distribution system exceeds 34 years (TR 37), MPC elsewhere verified that, on average, its distribution system would not need replacing for 34.5 years (MPC DR No. PSC 2-49). Then, on average, the cost today to replace the system 34 years from now is only a fraction of today's OSA replacement cost. For example, using MPC's assumed inflation and discount rates a dollar cost today escalated at 4 percent for 34 years and discounted back to 1988 has a value roughly 13 percent of today's cost. MPC's OSA estimate of marginal distribution costs grossly overstates the costs that would be avoided today. Clearly, sending a price signal equal to the replacement cost today of the distribution system would not allow MPC to avoid incurring the same amount of costs.

MCC stated that a price equal to the marginal cost of extending the distribution network or of adding a new service drop, while relevant to new customers, does not reflect the cost of continued service to existing customers, and does not encourage an optimal reallocation of resources among existing customers. MCC's argument reveals a trade off between short- and long-run costing. For new customers MPC's replacement cost approach has some merit. However, as MCC states, this is clearly the only area where improved efficiencies and conservation would occur (MCC Exh. No. 36, p. 28). The Commission finds this argument clearly demonstrates the serious flaws in both MPC's replacement cost approach and current line extension policies.

Although no testimony revealed the average remaining life of MPC's transmission and storage systems, the above argument also applies to the storage and transmission components of MPC's OSA. In the area of transmission and storage costs, there are inconsistencies between MPC's actual, and its hypothetical OSA investment plans for transmission and storage plant. MPC admits it cannot operate today with OSA related facilities (MPC Exh. No. 18, p. KMS-11).

MPC's actual expansion plans can be compared to the OSA plans (MPC DR PSC-1-8-ii-a versus MPC Exh. No. 18, Exh. KMS-2). The two differ: plant in MPC's 10 year plan does not appear in its OSA. Yet MPC states its actual system is moving towards the system design in the OSA (MPC Exh. No. 18, Exh. KMS-2, and MPC DR PSC 1-8-ii-a and 2-36-i). The Commission believes that actual avoidable costs must recognize the existing system as a starting point. The OSA does not have any realistic basis.

Third, MPC only occasionally applies discounted present value analyses in its OSA. Although the Company does attach significance to discounting future costs, it chose not to do so with most costs in its OSA (MPC DR PSC 1-20-v, TR 93 and 108). While MPC's carrying charges and compressor costs rely on DPV analyses, MPC would not explain the approach applied to other costs (MPC DR PSC 2-49-i), stating it is inappropriate to discount future costs because such an approach assumes service cannot begin until the date at which the cost of the new system would be incurred (MPC DR 2-49-ii).

In its testimony, MPC cited certain portions of testimony of Dr. Paul Joskow. In the same Joskow testimony cited by MPC, he states how best to estimate long-run incremental costs:

> |W¬e can ... get an even more refined estimate of long-run marginal cost ... we ask the question: what is the change in the present discounted value of total generating costs that results from advancing or postponing by one year the system expansion plan? (MPC DR PSC 1-27)

Clearly, Dr. Joskow's preferred approach for computing long-run incremental costs differs from MPC's OSA (MPC DR PSC 2-54): Dr. Joskow finds merit in discounting to a present value those actual costs expected to be incurred. Thus, Dr. Joskow's marginal cost study represents one example where the approach taken in an electric cost study differs with MPC's perception of an OSA (see MPC Exh. No. 9, p. 24). MPC sharply disagrees with the above cited position of Dr. Joskow, as regards cost discounting (TR 67-69).

Fourth, the Commission finds a major inconsistency between MPC's support of the OSA approach, and MPC's application of the OSA results in pricing. The inconsistency here regards the obvious seasonality of costs resulting from the OSA, and the lack of seasonality in prices. The discussion of this issue, which is also connected to the concept of cost avoidance, appears later in this order under "seasonality of costs."

With the above in mind, the Commission will state its findings on how the remaining costs are to be functionalized, classified, allocated and reconciled.

Storage and Transmission. The Commission notes that storage and transmission cost development is problematic and should be reviewed, improved and revised as needed in future gas cost of service dockets. As noted above, the Commission rejects MPC's OSA and adopts, as modified below, MCC's storage costs. Using MPC's cost studies in this docket (listed in Table 5), MCC estimated the lowest cost to connect added loads to the existing S&T system (MCC Exh. No. 36, p. 7).

MPC criticized MCC's storage cost estimates on several counts. There are two aspects to MPC's rebuttal: 1) the theoretical correctness; and 2) the actual calculation. First, the Commission finds merit in MPC's contention that MCC's study could be improved by including the cost of storage facilities investments. However, the Commission disagrees with MPC's estimate. With MPC's rebuttal, MCC's unit storage cost estimate of $9.24/Mcf increases to about $55.00/Mcf. However, the Commission finds that MPC overstated the proper Mcf volume associated with this investment, by using an OSA-derived value of 188 Mcf. The Commission notes that in analyzing its own marketing programs, MPC used a value of 116 Mcf for the same variable (MPC DR PSC 2-32i, iii). The Commission finds this figure to be a more accurate measure of the cost of investment in reservoir pressure. As with other costs this figure needs revising to mid-year 1989 dollars. Although MPC also criticized MCC's approach for omitting certain transmission necessary to connect the storage, MPC has not logically or technically identified those costs.

However, in regards to MPC's concern that MCC incorrectly excluded storage facilities investments, a point of clarification is in order. The Commission does not believe the omitted storage facilities investments or "storage capacity costs," involve capital investments (MPC Exh. No. 22, p. 6 and MCC Exh. No. 36, p. 32). The cost MCC excluded is the cost of investment in reservoir pressure -- gas pressure -- required to force one Mcf from storage on peak day (MPC Exh. No. 19, p. 12).

In computing its marginal storage costs, MCC used a different level of peak day demands than it used to compute total storage costs: 224,149 versus 193,422 Mcf. The Commission will not revise MCC's 224,149 Mcf value as used to compute unit storage and transmission costs. The Commission will refer to the system peak it finds relevant for computing total storage (and transmission) costs (see "Allocated Costs," below). This peak day demand is MPC's value of 222,239 Mcf.

Although the Commission has adopted MCC's approach to storage cost development, two additional observations are appropriate. First, MCC stated that its analysis of marginal storage and transmission capacity costs is consistent with methods accepted by the Commission in prior electric dockets (MCC DR MPC 10). However, the order MCC cited did not address storage costs, and expressed concern for the approach MCC had taken (Docket No. 86.5.28, Order No. 5219b, Finding Nos. 273-274).

Second, MCC's stated reason for excluding storage facilities costs is that MPC has adequate existing storage capacity. However, the Commission is concerned with including very little storage, transmission or distribution costs, excepting short-run variable costs and certain opportunity costs, if adequate storage capacity exists. This concern stems from the ap pearance that MPC may have sufficient capacity for these three functions well into the future. Some possible indicators of this condition on the MPC system include: 1) MPC's effort to increase load, including winter peak load, via the Smart Choice program; 2) MPC's apparent lack of concern for efficiently pricing winter consumption based on costs, if in fact capacity is scarce; and 3) MPC did not curtail all of certain customer's interruptible loads during the time of a recent historical system peak (1983), although it appears about 20,000 Mcf could possibly have been curtailed during this record cold spell (MPC DR PSC No. 1-10-ii-1 and iv-c). The portions of those loads which were interrupted would suggest MPC's deliverability problem may have been localized around Kalispell and not a system problem.

While the above discussion largely focused on storage costs, the Commission also finds relatively more merit in MCC's transmission cost estimate. Again, the Commission has flatly rejected MPC's OSA. MCC's methodology, while not very robust, provides the minimum acceptable for purposes of this docket. MCC's estimate of $28.51/Mcf will be used in this docket to estimate marginal transmission costs.

In summary, and due to the above described Storage and Transmission cost and peak demand, there occurs a change in the estimated marginal cost. MCC's Storage and Transmission costs approximated $6.5 million. With the above noted modifications, marginal S&T costs will increase. As with other costs, MPC must adjust the cost figures to reflect the resulting opportunity cost of gas and to reflect mid-year 1989 dollars.

Distribution. MCC's and MPC's costing philosophies differ most in the area of distribution costs. MPC's marginal costs reflect the costs to rebuild the entire distribution system (OSA). As noted, the Commission has rejected the OSA approach. MCC's approach to costing the marginal distribution costs relies upon MPC's actual embedded costs, and is thus inconsistent with its own costing philosophy (TR 20, 44, and MPC Exh. Nos. 9, p. 46, and 10, pp. 2-3). The Commission finds neither approach appropriate, as neither provides even the minimum level of accuracy the Commission believes is necessary. Again, the goal of marginal cost pricing is to promote efficient resource allocation. Historic or embedded costs cannot, alone, bear upon prospective resource allocation. Based upon the record analyses presented herein by MPC and MCC, and consistent with the Commission's adoption of marginal cost theory, the Commission finds that, for the purposes of this proceeding, no distribution costs are avoidable. Accordingly, no costs are assigned to the distribution function. On balance, the Commission believes this result is better, in terms of avoided costs, than either of the approaches proffered by the parties.

As discussed at length above, it is not clear in this docket what distribution costs are actually avoidable. However, to reiterate an earlier MCC comment, the Commission finds it particularly relevant that MPC's distribution costs are avoidable by new but not existing customers.

Customer. MPC and MCC also differed on the computation of customer costs. The Commission finds appropriate MPC's attempt at consistency between gas and electric dockets, and with the below modification approves of MPC's estimates. The Commission's policy on why meters, regulators and service costs should be included in marginal cost studies, as adopted in previous dockets, in part, turns on the notion of opportunity costs. Nothing in this docket has persuaded the Commission to alter this viewpoint. MPC appears to agree with the Commission that at least the meter and regulator has an opportunity cost, while the service does not (MPC DR PSC 1-28-x, TR 21). MCC also concedes that this opportunity cost approach may have merit to valuing at least meters (MCC DR PMCC-7).

MPC must modify its customer cost development by extracting from its cost estimate those costs associated with the "service" and "stub" running from the Company's main to the customer's meter. These costs are sunk in the case of existing customers, but appropriate in a line extension policy for new customers. MPC's customer cost estimates will then account for meter, regulator and other customer-related expenses. As with other costs, the customer costs must be revised to reflect mid-year 1989 dollars.

The customer weighting process used by MPC will not be changed in this docket. MPC provided a detailed explanation of the weighting process (MPC DR MCC 2-12), but would not provide a break out of unit costs by customer class (MPC DR PSC 2-6). The Commission finds that in its next gas cost of service study, MPC must report on the marginal costs of state of the art gas metering equipment, including demand meters.

Classified Costs

In this section of the order the Commission will address how functionalized costs are to be classified. The classification from Table 1 includes energy, peak demand and customer (or access). Note that a discussion of seasonal costs occurs in the section on allocated costs.

Production. Production costs are clearly energy related and should be classified as such. MPC's energy data are normalized and separated out by seasons for the 12 month period ending December, 1985, or the market period of September 1, 1986 to August 31, 1987. MCC and MPC used the same Mcf volumes in this regard (contrast Table 3 above with MCC Exh. No. 36, Exh. J.D. 1, p. 5).

Although MPC and MCC compute an annual cost for line losses, the Commission finds merit in marking up gas production costs to reflect use and line losses at the various levels of service, as is done in electric dockets. <u>See</u> Finding Nos. 117-119.

<u>Storage, Transmission and Customer</u>. Storage and transmission costs must be classified according to the percentages used by MCC. The Commission notes that the classification of storage and transmission costs needs further consideration in future dockets. Customer costs are by their very nature classified as customer related.

<u>Allocated Costs</u>

The Commission has a number of comments and findings on the class allocation of costs classified as energy, peak demand, and customer related. In addition, this section addresses the seasonality of costs, and the year's dollars for cost development. First, in regards to production energy costs, the volumes used by both MCC and MPC shall be used to allocate the same costs to classes. These volumes should not include use and loss adjustments, due to the inclusion in costs of MPC's use and losses (MPC Exh. No. 18, Exh. KMS-5).

Second, the Commission is concerned with how classified storage and transmission costs are allocated to classes. These concerns relate to MPC's system peak demand. A brief outline includes the following issues raised by MCC and GFG: MCC chose to not use the recent (1983) coldest winter peak demand, but rather a peak demand reflective of warmer weather from a more recent year; MCC includes interruptible loads in arriving at its system peak demand; GFG contends that MPC's estimate of GFG's contribution to the system peak demand should be lowered, reflective of interruptible loads on the GFG system.

The Commission adopts MPC's proposed system peak demand. Excluding interruptible loads, MPC used a value of 222,239 Mcfs of peak demand. MCC's corresponding figure was 172,550 Mcfs (excluding interruptible loads). That is, MPC's estimate of firm load contributions at the time of the system peak exceeds MCC's by 28.8 percent. In its final figure, the MCC includes interruptible industrial loads at the time of the system peak for allocating demand type costs, resulting in 193,422 Mcfs of peak demand.

By making a simple adjustment to MCC's estimates to reflect the higher number of heating degree days in 1983 relative to 1985, MCC's values increase considerably. The highest monthly heating degree days experienced in 1983 exceeded that in 1985 by 21 percent (MPC DR MCC 1-21). Adjusting MCC's firm peak demand of 172,550 Mcf by a factor of 1.21, MCC's peak demand rises to 208,786 Mcf. As an aside, but in support of using coldest weather conditions, is the fact that electric load and resource planning often makes a critical water assumption. Similar planning assumptions are appropriate for the gas side as well (MPC Exh. No. 19, p. 8). Similarly, if MPC ever achieves open access status, the difference in value between peak and normal weather loads would undoubtedly be of concern.

The Commission finds theoretically incorrect MCC's allocation of peak day demand costs to interruptible customers. However, the Commission will revisit this issue in MPC's next gas cost of service and rate design case. While in the recent past customers have not been interrupted with great frequency, there is no guarantee the need will not arise in the future (MCC DR PMCC 6). That the Commission finds relatively more merit in MPC's peak-day demand, and adopts the same, does not mean there are not any deficiencies.

The Commission believes that MPC's analysis underlying its peak demands for firm loads may lack two practical adjustments: 1) elasticity impacts; and 2) conservation impacts. The two impacts may be related e.g., price induced conservation versus programmatic conservation. Although the Company has stated its peak demand values are forecast values (MPC DR PSC 1-13-viii-c), MPC also states that it has not developed and applied elasticity impacts to its load and resource balance, as it does on the electric side of the business (MPC DR PSC 1-16).

The Commission is also concerned with MPC's apparent neglect of the impact of conservation on its 1983 system peak demands. MPC contends that since 1983, conservation has had no apparent impact on peak or annual demand (MPC DR PSC 3-3-v-a), but then states that lowered prices to GFG would reduce the incentive to add insulation in new homes with a potentially significant long-run impact on gas demand (MPC DR PSC 3-7-ii). These two points are inconsistent. Adjustments for both increased future gas prices and past conservation investments would seem to lower MPC's proposed system peak demand, other things being equal.

GFG argues that MPC overstated its contribution to MPC's system peak demand estimate. This issue appears to be a contractual problem (see MPC DR PSC 1-13-i-c and TR 123). If MPC needs added interruptible load and GFG is willing to make certain loads verifiably interruptible, it would seem MPC should recognize such benefits in its prices to GFG. With interruptible loads e.g., Montana Refinery, it would seem that GFG must insure the load could be shed by MPC during system peaks, so that MPC would not effectively be providing standby service (TR 159, 242). Apparently, GFG has not provided such assurances. Accordingly, the Commission rejects GFG's arguments in this regard.

As an aside, there is an inconsistency between which GFG loads were interruptible in GFG Docket No. 87.7.37 and the present docket. In GFG gas Docket No 87.7.37, an order was issued finding that large dual fuel (LDF) loads were not interruptible (Order No. 5313a, Finding No. 38). GFG did not challenge this finding. In the present docket, GFG noted its LDF loads are interruptible. This appeared to create some confusion for MPC (TR 233, MPC Exh. No. 19, p. 6).

Seasonality of Costs. In this section of cost allocation, the Commission finds appropriate a discussion of seasonal cost-based prices and inverted-block based prices. The testimony of both MPC and MCC expressed concern for inefficient resource allocations arising from noncost based prices. The following reviews both positions regarding seasonal prices and each party's estimate of seasonal cost differences.

MPC's position on the merit of cost-based seasonal price differentials appears confusing and inconsistent. The inconsistency regards conflicting reasons offered by MPC as conditions for tariffing cost-based seasonal prices, combined with MPC's reluctance to propose seasonal prices. As noted earlier in this order, this discussion is also one important reason that the Commission finds merit in rejecting MPC's OSA: That MPC does not find enough validity in the results of its cost study to support seasonal prices seriously challenges the integrity of the OSA.

MPC's testimony on cost-based prices is also inconsistent on two counts including: 1) within this docket; and 2) between this docket and the recent electric Docket No. 87.4.21. Although not proposing seasonal prices, MPC stated that the winter price should not be set below winter marginal cost, and that the Commission should be concerned with uneconomic winter consumption (MPC DR PSC 1-24 and 2-51). MPC's argument for not proposing seasonal prices is reflected in the following:

> |C¬harging a higher price in winter would not encourage load shifting from winter to summer to any measurable degree, but could result in customers switching their fuel usage from natural gas to an alternative fuel, a situation the Company is trying to discourage.... (MPC Exh. No. 27, p. 13)

This quote strongly suggests that if a higher winter price did cause winter load to shift to the summer, MPC would propose a higher winter price, but because cost-based seasonal prices only lead to economic fuel switching, the Commission should ignore costs in designing prices. In contrast to the above, MPC argued for seasonal prices even if gas customers were to change their gas demand by economically switching to alternative fuels (MPC DR PSC 1-30-ix-e). This later position is <u>inconsistent</u> with the above quote. In this regard, the Commission believes that there would be a response to increased winter prices, a point MPC concedes but did not quantify (MPC DR PSC 2-47 and 2-52).

MPC's rationale for not proposing seasonal gas prices, as quoted above (MPC Exh. No. 27, p. 13), is also inconsistent with its philosophy concerning seasonal electric prices. With electricity, MPC stated that the reason it proposed a residential seasonal differential was <u>not</u> because customers would shift load to the summer, but rather that they would simply reduce their load. That is, in the case of electricity, MPC proposed higher winter prices to hold down winter peak demand even if customers switched fuels (MPC DR PSC 2-55-ii-1 and testimony of Dr. Spann, Exh. No. 7, p. RMS-27 in MPC Docket No. 87.4.21).

Seasonal prices would not harm MPC's system load factor. MPC stated its proposed prices achieve the objective of maximizing throughput in the summer months, although the winter/summer capacity factors differ by 123 percent (winter of 70.7% and summer of 31.7%), using the Company's actual market for the 12 months ending August, 1987 (MPC DR PSC 1-25).

Finally, MPC provided estimates of seasonal costs based upon the OSA, which determined that seasonal peak usage doubles the cost of transmission and storage. MPC also stated that incremental seasonal costs are properly assigned to winter loads (MPC Exh. No. 9, p. CEO-34). Based on the <u>moderated</u> OSA cost results, MPC computed a summer price of $2.406/Mcf and a winter price of $3.30/mcf (MPC DR PSC 1-30-ix-c). This result assumably applies to all classes.

Using the unmoderated cost results from MPC's OSA, the winter/summer cost differential exceeds that computed above. The below table provides data for this calculation. The peak demand costs alone, if recovered via all firm load Mcfs, result in a $.47/Mcf increased winter cost. If the total S&T winter commodity costs are divided by the total winter market, and the result is reduced by the unit summer S&T costs, the result is an additional $.56 increased winter cost. Thus, from MPC's OSA, firm loads lead to at least a $1.03/Mcf in increased winter costs. Moreover, this result excludes any seasonal differences in distribution costs from MPC's OSA. Interruptible loads should also face a higher winter than summer price if MPC's OSA cost results are valid.

Table 6
Unmoderated Seasonal Costs
From MPC's OSA

	Peak Demand Costs	Commodity Costs Summer	Commodity Costs Winter
Transmission	$2,858,561	$5,589,394	$11,867,626
Storage	3,675,157	0	6,128,354
Total S&T Costs	6,533,718	5,589,394	17,660,008

	Without Interruptible	With Interruptible
Winter Mcf:	13,838,571	15,951,419
Summer Mcf:	NA	10,270,615

Source: MPC Exh. No. 21, Exh. HAW-6, p. 2, Exh. HAW-8, p. 2 and Exh. HAW-9.

From MCC's cost study a winter/summer cost-based price differential is also justified. MCC conceded MPC's costs vary by season, but did not propose seasonal prices. MCC clearly attributes all storage costs to the winter peak season or period (MCC Exh. No. 36, pp. 31-33). MCC's combined storage and transmission cost of $37.75 translates into a $.404/Mcf adder to the production cost of gas (MCC DR PMCC-12). This $.404/Mcf increased winter cost estimate is conservative, in that it does not reflect the adjustment MPC proposed to revise MCC's storage costs to include incremental storage inventory costs. MCC stated that implementing a moderated inverted-block price structure may not be too radical a change in the present docket (MCC DR PMCC-8).

Year's Dollars For Cost Development. At various points in this Order, it has been noted that MPC must recompute costs using mid-year 1989 dollars. Every marginal cost study must state the year's dollars in which costs are estimated. This decision does not differ from Commission decisions in other recent dockets. In short, the reason for updating MPC's cost study is to use the most current costs possible for purposes of computing marginal cost based inter- and intra-class revenue requirements.

In this docket, the parties used different year's dollars in their cost studies. MPC states it used real 1987 dollars. However, some of MPC's costs were discounted, some were current costs and other's were a simple arithmetic average over a number of years. MCC also used a mix of year's dollars in its cost study. MCC's AGA gas costs were in 1988 dollars. Since MCC used MPC's storage and transmission costs, these costs were in real 1987 dollars. Finally, MCC added the above costs to embedded distribution accounting costs.

In response to a data request asking why all costs should not be adjusted to mid-year 1989 dollars, MPC stated, in part:

> The import that should be attached to this docket is that the studies performed in this application are to determine the structure of rates not the total revenue requirement to be recovered through rates. There is no reason to expect changes in general prices that might transpire between January 1, 1987 and January 1, 1989 to affect the important results of the cost of service study which are to determine the proportions of total revenue requirement that should be paid by each customer class. (MPC DR 1-29-ix).

Simply stated, MPC expects no structural changes. Given MPC expects no structural changes, then the revision should cause MPC no problems.

The Commission finds that MPC's revised cost study, filed in compliance with this Order, must use mid-year 1989 dollars. The reasons seem obvious and are numerous. First, the use of real carrying charges assumes an inflation adjustment each year. Since MPC's costs are in real 1987 dollars an adjustment should be made through time. The NERA report MPC cites as its source of carrying charge development states: "The annual charge according to the formula rises at the rate of inflation." (MPC Exh. No. 9, p. 24). The cited "annual charge" is the same that MPC used in its study, and that MCC in turn used (MPC Exh. No. 18, Exh. KMS-7, p. 3).

Since it is nearly mid-year 1989, the same year's dollars seems appropriate if not conservative.

Reconciliation

Reconciliation is the last step in a general cost of service model, and arises as an issue when marginal cost revenue requirements differ from the allowed revenue requirement. The MCC and MPC disagree on how reconciliation should proceed in this docket. The Commission concurs with MPC's approach to apply an equi-percent approach at the inter-class revenue requirement stage. Under this approach, each rate class recovers an equal percentage of its marginal cost revenue requirement. However, just as MPC employed a second level of reconciliation, called moderation, to address bill impact concerns, the Commission also finds merit in further adjustments to reflect bill impact and efficiency concerns. This will be reviewed in the order on rate design to be issued in this docket. See Finding of Fact No. 175.

The Commission's preferred reconciliation approach is the same as that adopted in all recent cost studies. See Docket Nos. 83.9.67, 86.5.28, 86.12.76 and 87.4.21. The Commission believes that inter-class cost allocations and intra-class rate design should, to the extent practical, reflect inverse elasticity (Ramsey pricing) concerns. MCC's reconciliation approach appears to be an application of inverse "inverse-elasticity" pricing. The Commission firmly believes that the elasticity of demand for the Commodity gas, as reflected in the $/Mcf charge, is greater than that for access as reflected in the monthly Service Charge.

MPC's Compliance Filing

The Commission chooses to bifurcate the final orders issued in this docket, to separately address cost of service and rate design. The Commission finds that MPC must revise its cost study to reflect the Commission's decision in this Order. From the revised study MPC must provide the following information. First, MPC must compute and provide unit costs per proposed class for each of energy, demand and customer, with energy costs separately reported for each season and averaged for the year. MPC must also report the demand costs on an energy basis.

Second, the Commission finds MPC must compute and provide prices that generate each class' moderated revenue requirement. For the residential class, the first scenario will use MPC's proposed customer charge with the balance of the revenue requirement recovered in the commodity price. The second residential scenario requires MPC to again use its proposed customer charge, but tariff seasonal prices. The winter price must be $.40/Mcf greater than the summer price.

For the proposed General Natural Gas Service class, the first scenario will use MPC's proposed customer charge and recover the balance of the class' revenue requirement from the Company's proposed declining-block tariff proposal, with a price differential that is consistent with the Company's testimony. The second scenario is the same as the first, except for a flat commodity price. The third scenario is the same as the first, except for seasonal prices with a $.40/Mcf winter/summer differential. A fourth scenario is the same as the second, but for seasonal prices with a $.40/mcf winter/summer differential.

For the Firm Utility class the following price scenarios must be analyzed: First, compute an annual average commodity price; Second, assume a $.40/Mcf winter/summer differential.

For the Interruptible Industrial Gas Contract class, the following scenarios must be computed: First, using the Company's own proposed Customer Charge, compute the resulting aver age annual commodity price; Second, using the same commodity price as in the first scenario, compute seasonal prices assuming a higher winter price by $.40/Mcf.

Interruptible, Retention and Incentive Rates

The Commission granted interim approval of MPC's incentive (NGI) and retention (IMR) tariffs. In this Order, the Commission will address certain cost related policy issues underlying the design of both tariffs. Some cost issues common to both tariffs include interruptibility and line extension costs. As with all other tariffs, the Commission defers pricing decisions until the rate design order.

As a general matter, the Commission finds merit in the objectives served by these tariffs. The Commission is concerned that these tariffs may not maximize benefits or identify all relevant costs. The key is in the timing and price levels as demonstrated by the following discussion.

As discussed below, the Commission finds particular merit in MCC's position on the relevance of marginal costs. MCC has testified that discounted prices for either the IMR or NGI tariffs may be unnecessary as long as customers that request such service are required to pay the full marginal cost of the associated service (MCC Exh. No. 36, pp. 62-63). The following discussion supports this marginal cost perspective raised by MCC.

Interruptibility. Both the IMR and NGI tariffs feature interruptibility. Of chief concern to the Commission is that interruptibility not be used to justify a discount in the absence of need. The sort of analysis that appears absent in the present docket involves a valuation of interruptible loads. Interruptibility appears simply as an added benefit and condition with incremental IMR and NGI loads that MPC retains and attracts (MPC DR PSC 2-59). However, as shown below, since the amount of load that could be interrupted was adequate before the NGI and IMR loads, certain other interruptible (non-IMR and non-NGI) customers should perhaps cease to receive interruptible discounts as MPC adds IMR and NGI loads. MPC appears to consider the optimal quantity and geographic location of interruptible loads to not be a cost issue (MPC DR PSC 1-10-iv-d, 1-30-i-b and 2-60).

Using data on the extent to which MPC has actually interrupted loads, relative to potential interruptibility, the following illustrates that MPC may have a substantial cushion of interruptible loads, and very possibly an uneconomic excess of interruptible loads. MPC appears to lack incentives to optimize the amount of interruptible load.

Except for any interruptions since the May, 1988 hearing, MPC invoked the interruptible provisions of its contracts with 12 different customers, one each time since 1980. The maximum period of interruption was 18 hours, the minimum 8 hours, and the average length 11 hours (MPC DR PSC 1-15 in Docket No. 85.7.32). Moreover, in most cases only a portion of a customer's load was interrupted. That is, all interruptible loads were not simultaneously interrupted: all loads were not simultaneously curtailed.

Since January, 1984, no loads have been interrupted (MPC DR PSC-1-23 in Docket No. 87.3.16 and MPC DR PSC 1-10-iv-c). In 1986 for example, MPC had about 4.4 Bcf of interruptible load, or roughly 17 percent of its Montana market. The ratio of interruptible loads to total Montana loads appears fairly constant, especially when compared to the 1970s (<u>see</u> MPC DR PSC No. 1-13-ix, attachment). Assuming 4.4 Bcf of interruptible load each year since 1980, the percent of load actually interrupted of the total interruptible load delivered is only about .03 percent (MPC DR PSC 2-38-vi).

Clearly, a valid concern arises regarding MPC's need for additional interruptible load. MPC states it is not concerned with acquiring too much interruptible load, as any loss of revenue attributable to truly interruptible gas load can be offset by a corresponding reduction in cost if interruptible prices properly reflect costs (MPC DR PSC 1-13). However, MPC admits not analyzing the costs and benefits of interruptible loads (MPC DR PSC 2-60).

Importantly, perhaps MPC would benefit from being able to interrupt certain of GFG's loads. However, no cost analysis by MPC supports such a conclusion in this docket.

The Commission believes that MPC has not studied and optimized the price extracted from, or the optimal amount of, interruptible loads. Given the limited amount of load actually interrupted, the value of existing interruptible loads on the Interruptible Industrial tariff would seem diminished due to added IMR and NGI loads (MPC DR PSC 1-13-i-b).

Line Extension Costs. With the NGI and IMR tariffs, the Commission is concerned with the responsibility for the costs of line extensions to serve these loads. As regards the NGI tariff, MPC responded that other customers' prices will be affected if MPC makes the investment (MPC DR MCC 1-7). This position appears to conflict with MPC's opinion on who should pay for NGI line extensions (MPC DR MCC 4-26). The Commission believes that any investments made to serve NGI or IMR loads must be paid for by the customer for which the investment was made.

Consistent with the above discussion, the Commission will now address the unique aspects of the NGI and IMR tariffs.

Natural Gas Incentive. The chief concern raised in the Commission's interim order approving the NGI tariff remains today:

sales must cover incremental costs. To this end "opportunity costs" are relevant as proposed by MPC's NGI testimony. On its own initiative, the Company listed the following costs any NGI price must recover:

1. The net present value (NPV) of the revenue requirement created by having to make an investment to service the load, if other customers' prices are impacted.
2. The incremental cost of gas, including variable non-gas costs.
3. The NPV of any future gas supply cost penalty.

MPC's NGI filing represents the first occasion that a Company has proposed the Commission directly consider "user costs" in the context of addressing the merit of cost-based prices (MPC DR 1-26 and 1-34 in Docket No. 87.3.16 and MPC DR No 1-13-vi-c,d and 2-42-i).

While the Commission has directly considered the notion of opportunity costs, e.g., the recent electric avoided cost docket (No. 84.10.64), the context has changed. Prior applications involved considering spatial opportunity costs at a given point in time. In this docket, MPC has raised the issue of temporal opportunity costs, or user costs. MPC's interest in, and application of, user costs appears limited to its NGI tariff.

A simple but practical example of MPC's notion of user costs is illustrated as follows: If MPC could sell an Mcf of gas in a future period, and if the discounted present value of the sales price in the future period exceeds the price at which MPC sold gas today on the NGI tariff, a user cost would arise. The cost of selling the gas today is forgone earnings in a future period, the discounted present value of which exceeds today's NGI opportunities.

Two issues which arise concerning user costs include the basis for the user costs and the appropriate discount rate. First, the Commission will not seek to define actual user costs in this docket. However, the Commission believes that if MPC is capable of making sales to other pipelines via the self-imple menting aspects of the NGPA, MPC's NGI sales should probably cover the spot market price of gas in the region in which MPC could make such a sale. Further, other cost adders may be appropriate. The Commission intends to revisit this issue in the future.

Second, and in regards to the appropriate discount rate, MPC has stated that it is not the market discount rate that is appropriate for discounting future costs, but the Company's own embedded cost of capital that is appropriate (MPC DR PSC 2-42).

This perspective of MPC's would assumably change if MPC's production function were deregulated.

A final issue with MPC's proposed NGI tariff concerns the flow-through of the price (minus incremental cost difference), to all other customers. MPC proposed 90 percent be credited to the unreflected gas cost account. The Commission required 100 percent be credited on an interim basis. The Commission finds no need to revise its interim decision to flow through 100 percent of the benefits.

The Commission's primary reason for finally rejecting MPC's proposal to credit only 90 percent of the NGI net revenues stems from the uncertain incremental cost basis in MPC's testimony for the "highest marginal cost." As evident from the testimony, MPC has not pinned down the basis for the "highest marginal cost" of gas, for purposes of computing the net revenues to be credited to the unreflected gas cost account (TR Vol. I, 35-36). From discovery it appears that because the NGI sales price has not fallen below $2.00/Mcf, actual user costs may not have occurred assuming spot prices are exceeded (if spot prices are the relevant floor). Also, and in support of denying the NGI 90/10 revenue sharing is MPC's conditioned admission that both customers and stockholders realize benefits for each MCF sold when gas is sold at prices in excess of incremental costs (MPC DR PSC 1-33, 2-62 and MCC 3-13).

Industrial Market Retention. The Commission finds need to continue the interim 90/10 risk sharing with this tariff. The basis for this decision relates to the same reasons the Commission denied MPC's 90/10 revenue sharing with the NGI. As with the NGI, MPC clearly has a fairly tentative position on what the relevant "highest marginal cost" is, below which IMR sales should not be made (TR Vol. I, 35-36). Second, the Commission finds that MPC should further study the need for added interruptible loads on its system. The opposition of both MCC and GFG regarding continued recovery of IMR revenue deficiencies via an unreflected gas cost tracking procedure will be deferred until MPC's next general gas case.

The above 90/10 risk sharing decision only pertains to sales that do not exceed a customer's base volumes. At this point, the Commission agrees with MPC that if IMR sales exceed a customer's base volume level, 90/10 debiting must be replaced with 100 percent crediting for all sales in excess of base volumes (MPC DR PSC 3-5-ii-b). However, the Commission is con cerned that "base volumes" may not be the only relevant consideration in deciding when to debit or credit revenues.

As with the NGI, the Commission is concerned about MPC's interpretation of the relevant marginal cost for IMR sales. While MPC proposed no "user cost" perspective with the IMR, the Commission is not convinced that the Company's NGI policy, in this regard, is not equally applicable to IMR sales. IMR sales prices, at present, appear to exceed the spot market price of gas which could serve as the relevant opportunity cost (MPC DR PSC 2-62).

Extension of NGI Availability. On April 17, 1989 MPC filed a request with the Commission to extend the availability of the NGI rate for a period of two years beyond the current term, to April 20, 1992. By Commission action, this request was consolidated into this proceeding for final consideration. This request was served upon MCC, as well as all other parties to this Docket.

The Commission notes that the next three years may bring about drastic changes in the day-to-day operations of MPC's gas utility. For example, by September 30, 1989, MPC has committed to filing with the Commission a comprehensive gas transportation plan, implementing some form of open access. With such proposals on the horizon, the Commission is reluctant to extend NGI availability until 1992. However, the Commission will extend the availability of the tariff for one year, in or der to allow for continuity in negotiations between MPC and NGI customers.

CONCLUSIONS OF LAW

1. All Findings of Fact are hereby incorporated as Conclusions of Law.

2. The Applicant, Montana Power Company, furnishes natural gas service to consumers in Montana, and is a "public utility" under the regulatory jurisdiction of the Montana Public Service Commission. < 69-3-101, MCA.

3. The Montana Public Service Commission properly exercises jurisdiction over Montana Power Company's rates and operations. < 69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

4. The Montana Public Service Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this Docket. < 69-3-303, MCA, < 69-3-104, MCA, and Title 2, Chapter 4, MCA.

5. The cost of service approved herein is just, reasonable and not unjustly discriminatory. << 69-3-330 and 69-3-201, MCA.

ORDER

THE MONTANA PUBLIC SERVICE COMMISSION HEREBY ORDERS:

1. The Montana Power Company shall design class cost revenue responsibilities to generate authorized revenues which are consistent with the findings entered by the Commission in this order.

2. The Montana Power Company shall submit its revised cost of service study, including its working papers, revealing in detail the structuring of unit costs and class revenue responsibilities. Also included shall be the specific information requested in Finding Nos. 175-179 herein, under the heading "MPC's Compliance Filing."

3. All documentation, as described above, shall be filed with the Commission no later than 21 days after the issuance of this Order.

4. All other motions or objection made in the course of these proceedings which are consistent with the findings, conclusions and decision made herein are granted; those inconsistent are denied.

Done and Dated this 10th day of May, 1989 by a vote of 5-0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

CLYDE JARVIS, Chairman

HOWARD L. ELLIS, Vice Chairman

JOHN B. DRISCOLL, Commissioner

WALLACE W. "WALLY" MERCER, Commissioner

DANNY OBERG, Commissioner

ATTEST:

Ann Purcell
Acting Commission Secretary

(SEAL)

NOTE: Any interested party may request that the Commission reconsider this decision. A motion to reconsider must be filed within ten (10) days. See ARM 38.2.4806.